Final ~~Draft for Review~~

~~October 23~~November 16, 2001

US Bureau of Reclamation Mid-Pacific Region
Post-2004 Operations
Options Analysis
Report and Recommendation

I. BACKGROUND:

The Federal Government must minimize economic impacts and ensure an orderly transition as it moves from operation under the PG&E Integration Contract No. 14-06-200-2948A (Contract 2948A) to operation in a restructured electric utility industry environment without Contract 2948A. To that end, US Bureau of Reclamation Mid-Pacific Region (Reclamation) developed a plan that described the approach Reclamation would take in migrating toward operation in a restructured electric utility industry. The plan identified six elements that were needed to make an orderly transition. The six elements were:

1. Evaluate California Independent System Operator (CAISO) interface options to maximize the power resource benefits and mitigate pumping costs.
2. Develop operating procedures for scheduling generation and pumping.
3. Develop procedures to interface and coordinate with environmental and fisheries resource agencies.
4. Develop policy for pass-through costs to the water and power customers.
5. Develop cost allocation and accounting procedure policies.
6. Identify operational strategies to mitigate power utilization costs.

This report concludes the first element of the plan that Reclamation, in collaboration with the Post 2004 Project Use Options Workgroup (Workgroup), made up from representatives of Central Valley Project (CVP) water and power customers, the Western Area Power Administration (Western), and the U.S. Fish and Wildlife Service (FWS), would evaluate the CAISO implementation options to maximize the Federal Resource. Based upon the concurrence of Reclamation's upper management and Department of Interior representatives, the results of the first element will be used in the implementation of the remaining five elements.

II. RECOMMENDATION:

The options have been analyzed and it has been recommended that Reclamation and Western initiate an operational strategy that maximizes the benefit of generation independently from the Project pumping operation (Project Use loads). All required power to support the pumping operation would be purchased from the market allowing the CVP generation to be shaped for

Maximum optimization. The priority of the authorized Project purposes, which generally has Reclamation reserving Project generation for pumping, is preserved through adjustment of cost allocation percentages between the authorized functions. This adjustment would be developed through a different workgroup, under element number four.

The option analysis further indicated it was more cost effective to retain Western as the Scheduling Coordinator for the Project since they currently have the existing infrastructure for interacting with the CAISO. Reclamation does not have the necessary power accounting/scheduling infrastructure required to implement the CAISO protocols outside of Contract 2948A and would be required to incur substantial start-up costs in staff and Information Technology infrastructure.

III. ANALYSIS:

A. Operational Options Considered:

In order to make an in depth assessment of the interface options, the Workgroup and Reclamation enlisted the aid of a consultant to analyze the options. A prioritization matrix (Table 6) was developed by the Workgroup that ranked the analytical results based upon categories that were considered essential to the viability of the Project. The options were precluded from altering the releases to rivers or the pumping operations.

The Workgroup started its work in May 1999 and essentially concluded in November 2000. The analyses relied on data from the Central Valley Project Improvement Act (CVPIA) Programmatic Environmental Impact Statement (PEIS) preferred alternative, and Western's Environmental Impact Statement for its Post-2004 Power Marketing Plan, sixteen years of daily and hourly operational data, reservoir operating criteria, Reclamation and Western's functional capabilities, and current staffing levels at Reclamation.

The Options considered were:

1. New Integration Contract:

Enter into a new integration agreement with a third party and/or Western that would contain similar terms and conditions as the existing integration agreement with PG&E and would offer the same level of service. While the existing operations would not need to change, it was anticipated that a new agreement with another entity could be considered an administrative action and could warrant some form of NEPA review. The CVP operation would not change the quantity of water released on a daily basis to the river. The release rate into the regulating reservoirs would be within the designated operating range reserved for that purpose.

2. Pump Load Following:

Submit to the CAISO, directly or through a Scheduling Coordinator, a generation schedule that matches the Project Use pump load to the degree possible. This action would still be within the operating range of the existing integration agreement; however, it would be a departure from what may be considered "current" or "normal" operations and could warrant some form of NEPA review. The CVP operation would not change the quantity of water released on a daily basis to the river. The release rate into the regulating reservoirs would be within the designated operating range reserved for that purpose.

3. Maximum Peaking Generation:

Submit a generation schedule, directly to the CAISO or through a Scheduling Coordinator that is developed independent of the Project Use pumping schedule. This action would be within the operating range of the existing integration agreement and reflects the current operations (this ranges from Maximum Peaking to flatter loading patterns). No NEPA further review would be required since the existing operations would be carried forward into the future. The CVP operation would not change the quantity of water released on a daily basis to the river. The release rate into the regulating reservoirs would be within the designated operating range reserved for that purpose.

B. Method of Analysis:

Each option was analyzed against a set of weighted criteria to provide a quantitative framework to determine the feasibility of each option. The parameters were:

1. Operational analysis: - The financial cost to support Project loads and value the surplus generation;

2. Administrative analysis: - the financial cost of interfacing with the CAISO;

3. Operational flexibility: - to what degree does one option allow greater flexibility of the Project in meeting or providing additional environmental benefit; and

4. Compliance with environmental documentation: - Review of existing environmental documentation for adequacy.

Several consultants were hired by Reclamation to perform the (1) operational and (4) environmental analysis. In order to ensure independence in their evaluations, neither consultant was aware of the Workgroup's prioritization matrix as they performed their assessments. Details of the analysis are included in relevant subsections.

A significant amount of Workgroup time was spent discussing Option 1, the New Integration Contract. The principle issue focused on how to determine what a third party would want as compensation for serving CVP loads when generation was not sufficient. The Workgroup concluded that a third party would either want to reduce the amount of generation or would require payment as compensation. The amount of compensation would be determined through negotiations. Based upon these conclusions, a consensus within the Workgroup was reached and Option 1 was not included in the Operational Analysis.

(1) Operational Analysis:

CVP system operations were examined against the Load Following and Maximum Peaking options. The primary difference between theses two options was the approach used to meet Project Use loads. For the purposes of this analysis, under the Load Following Option, Project Use loads were met, to the extent possible, through CVP generation. The remaining generation "surplus" was then optimized and valued according to forecasted market prices of energy. Thus, this alternative, provided for CVP generation schedules support Project Use loads.
Under the Maximum Peaking Option, Project Use loads were met through market purchases, leaving available CVP generation for optimal dispatch to preference power customers based on a Pricing formula. This alternative, provided CVP generation schedules that were developed independent of Project Use loads. The analysis for both Load Following and Max Peaking was performed using an hourly model of the CVP constructed from operational data and applied to three different hydrologic year types (Wet, Median and Dry). An hourly analysis provided the highest degree of accuracy possible. Use of operational data ensured that unknowns such as outages, maintenance patterns, and weather events were captured in the data set. The hourly models also allowed accurate assessment of the full range of hydropower products.

For the purposes of the analysis, the "benefit" of the CVP generation, in a Post-Contract 2948A period was based on an hourly energy price. The use of this hourly energy prices put the CVP generation as the last resource supporting loads. This was irrespective of the loads being Project Use or Preference. No discounts were made for forward purchases to support project loads under either scenario. The consultant developed a forward-looking model for the energy prices that were adjusted for hydrologic year types. The consultant also employed a dispatching model that emulated the manner in which the generation was dispatched based on the two options to capture the optimal hourly benefit. This dispatching model incorporated the appropriate lag to reflect the proper hourly price response. An estimate of the value of ancillary services was provided for each of the operational alternatives. An estimation of costs associated with Project Use loads was also determined for each option.

The operational data analysis results are summarized below in Table 1. The results listed are not allocated to any specific Project purpose:

TABLE 1
OPERATIONAL DATA SUMMARY

	WET YEAR		**MEDIAN**		**DRY**	
	Maximum Peaking	Load Following	Maximum Peaking	Load Following	Maximum Peaking	Load Following
Generation Value	$279,950,000	$244,523,000	$233,658,000	$184,929,000	$151,979,000	$130,497,000
Pumping Support Cost	$33,699,000	$140,000	$46,098,000	$181,000	$23,939,000	$4,542,000
NET VALUE	$246,251,000	$244,383,000	$187,561,000	$184,747,000	$128,040,000	$125,955,000

The difference between the two options demonstratesd that a significant net value is accomplished under all water year types for the Maximum Peaking option. The analysis was performed at an hourly level allowing a high degree of accuracy. The net value was found to be primarily a function of the difference between the on-peak and off-peak hourly prices. As a further demonstration of this effect, the following Table 2 illustrates this point. This table isolates the modeled data for Shasta power operations and analyzes the effect of increased, on-peak energy to off peak prices differences to the net value bottom line. This table indicates that as the differences between on and off peak energy prices increase, the net monetary difference between the two options gets significantly larger.

TABLE 2
SHASTA POWER OPERATIONS
Responsiveness of Options to Increased Prices

	NET VALUE			% CHANGE
CATEGORY	Maximum Peaking (MP)	Load Following (LF)	DIFFERENCE (MP-LF)	
Modeled (BASELINE)	$ 830,644	$ 579,742	$ 250,902	
5% Increase in "On-Peak" Prices	$ 886,782	$ 607,892	$ 278,890	11%
10% Increase in "On-Peak" Prices	$ 942,920	$ 636,043	$ 306,877	22%
15% Increase in "On-Peak" Prices	$ 999,059	$ 664,193	$ 334,866	33%
20% Increase in "On-Peak" Prices	$ 1,055,197	$ 692,343	$ 362,854	45%

(2) Administrative Analysis:

Under each option, the additional administrative costs incurred as a result of interfacing with the CAISO were also analyzed. No attempt was made to analyze the costs that a third party would assess Reclamation for interface services, as this would be negotiated under a procurement process. Both Western and Reclamation would however, incur costs in providing information to the third party interface. The analysis of administrative costs assessed the need for additional staffing, the respective agency computer infrastructure changes to hardware/software, and other costs that each agency would incur under each specific options.

The tables presented below summarize the financial impacts of additional staffing and infrastructure items for each option. A salary multiplier of 2.25 was used in the calculations in order to provide for coverage during vacation, sick leave and meeting/training coverage. The costs for personnel were derived using existing Federal General Schedule pay rates, and assumed that Reclamation could recruit staff under these pay rates.

TABLE 3
STAFFING IMPACT TABLE

OPTION	ADDITIONAL POSITIONS	ANNUAL SALARY	ANNUAL COSTS
1, 2, and 3 with Scheduling Coordination provided by a Third party or Western	Two Project Load Schedulers One Post Accounting Position	Two @ $80,000 One @ $50,000	$472,500
2 and 3 with Reclamation as its own Scheduling Coordination	Two Project Load Schedulers Three Post Accounting Positions Two Hardware/Software Positions Two "Traders" Five real-time	Two @ $80,000 Three @ $50,000 Two @ $50, 000 Two @ $80,000 Five @ $70,000	$2,070,000

Besides staffing impacts, there were some associated hardware and software costs required for interface with the CAISO. The impacts are shown below. The listed impacts assume dual hardware servers, and a scheduling and accounting package similar to the ACES system developed by Unified Systems, Inc.

TABLE 4
IT INFRASTRUCTURE IMPACT TABLE

OPTION	SCHED. & ACCT. PACKAGE	CVP MODELING	HARDWARE	TOTAL COSTS
Integration Option	0	0	0	$0
Load Following and Maximum Peaking with Western as Scheduling Coordinator	0	$50,000	$10,000	$60,000
Load Following and Maximum Peaking with Reclamation as Scheduling Coordinator	$200,000	$120,000	$50,000	$370,000

Other administrative costs not addressed in the previous tables included the non-recurring costs of office moves associated with the options. The costs for moves were calculated based on One-day, (8 hours) productivity loss for five people at a loaded cost of $67 per hour or $2,700. This amount is added to the cost of moving two people at $400 each per day, and a fixed fee of $200. This totals $1,000. The total for office moves would then be $3,700.

Note that none of these costs included any costs for Reclamation contracting out the role of Scheduling Coordinator. These are raw costs for personnel, hardware, software and reorganization.

A summary of all the administrative cost analyses results is summarized below.

TABLE 5
SUMMARY OF ADMINISTRATIVE COSTS

OPTION	NON-RECURRING COSTS	ANNUAL COSTS	NORMALIZED COSTS
Load Following with Third party as Scheduling Coordinator	$3,700	$472,500	19.5%
Load Following with Western as Scheduling Coordinator	$63,700	$472,500	21.9%
Load Following with Reclamation as Scheduling Coordinator	$373,700	$2,070,000	100%
Maximum Peaking with Third party as Scheduling Coordinator	$3,700	$472,500	19.5%
Maximum Peaking with Western as Scheduling Coordinator	$60,000	$472,500	21.8%
Maximum Peaking with Reclamation as Scheduling Coordinator	$373,700	$2,070,000	100%

Based on the summary data, it was evident that if Reclamation were to take on the role of a Scheduling Coordinator, they would be substantially financially impacted. Alternatively, it appears that either having Western or a third party act as a Scheduling Coordinator has the least financial impact to Reclamation.

(3) Operational Flexibility:

This parameter, when analyzed against each of the options, was intended to assess the operating flexibility of the Project in meeting or providing additional environmental benefits. While the analysis of this parameter did not yield objective results as the previous two parameters, the analysis did indicate that one option provided significantly more flexibility than the others did.

Under all options, mandated environmental requirements have been met. The operational flexibility of the Project is needed to achieve specific environmental objectives, which generally are not mandated; however, if achieved could improve certain habitat conditions. In order to make a sound decision, the options were assessed to determine if operational flexibility was lost or maintained or gained under the various options. The options were evaluated not from the perspective of when the releases occurre and how that release pattern would support environmental objectives. Releases that are not prescribed in advance can be made to coincide with environmental objectives. Under the Load Following option, water releases are preset based upon the pumping schedule. This requires water releases to be made from the storage reservoirs irrespective of any other benefit. The water cannot be delayed by even one hour or the Pumping schedule cannot be supported. In some cases, after meeting the environmental requirements and pumping schedules, there was no other water available in the release schedule. By contrast, the Maximum Peaking option has sufficient latitude that a delay of one hour may not produce a significant difference in peaking benefit while supporting an environmental objective. This gives the Project operators more resources to achieve some additional environmental objectives. Therefore, of the two options evaluated, it was found that the Maximum Peaking option-provides greater operational flexibility, while the Load Following Option does not.

(4) Compliance with Existing Environmental Documentation:

This review examined the CVP operational options, and compared these options to the operational constraints and opportunities contained in the CVPIA PEIS and Western's Post-2004 Marketing Plan EIS. The intent of the comparison was to determine if the options were within the parameters of the CVPIA PEIS and the Post-2004 Marketing Plan EIS, and if the options would likely create or cause an environmental impact. Reclamation hired a consultant, acting independently of the others, to perform the review.

Anticipated impacts that would result from implementation of Load Following Option appear to fall within the parameters of the alternatives examined in the Post-2004 Power Marketing Plan EIS. The impacts and/or effects (negative or positive) that the Load Following Option could cause are likely to be very similar to those identified in the preferred alternative in the Post-2004 Power Marketing Plan EIS.

(5) Costs:

Most anticipated impacts that would result from implementation of Maximum Peaking Option were very similar in type and scope to those identified for Load Following Option. One difference was, there could be a potential increased water costs due to increased water pumping due to exposure to schedule deviation, ISO charges, and infrastructure costs depending on how costs are allocated.

An increased per unit cost for CVP power is more likely to remain a viable component of a customer's resource mix if the CVP resource can be made more valuable through Peaking Management power. The creation of additional value of the power resource through Peaking Management could help maintain the feasibility of the CVP as a competitive alternative in California's deregulated energy market. This is essential if repayment of the Project, as currently configured, would continue without threat of default.

While the CVPIA PEIS present's additional operational constraints for the CVP, neither the CVPIA PEIS nor the Post-2004 Power Marketing Plan EIS, presented any additional constraints on the marketing of CVP power. However, considering (a) the intent of both the CVPIA PEIS and the Post-2004 Power Marketing Plan EIS to increase the flexibility of the CVP, (b) the potential increased cost of CVP power due to additional environmental costs, and (c) the development of a more liquid market for purchased Replacement power in California, it may be appropriate to consider the pursuit of statutory and/or policy changes that allow greater flexibility in the power operations of the CVP.

C. Method of Prioritization:

The options prioritized by the Workgroup by using an objective weighting method. The group identified three primary areas of interest: overall net benefits of resources to loads, additional administrative costs, and additional operational flexibility. These areas were identified along with their relative weights prior to the results of any of the analyses being made known. The following chart illustrates how the matrix was applied.

TABLE 6
PRIORITIZATION MATRIX

Priority Matrix Category	**Weighing factor** 1	**Weighing factor** 2	**Weighing factor** 3
Net Benefits of Resources/Loads	Option is in upper third of normalized net benefits.	Option is in middle third of normalized net benefits.	Option is in lower third of normalized net benefits.
Agency Additional Administrative Cost	Option is in lower third of normalized costs.	Option is in middle third of normalized costs.	Option is in Upper third of normalized costs.
Operational Flexibility	Option provides additional operational flexibility to meet environmental objectives.	Option provides no additional operational flexibility to meet environmental objectives.	Option reduces operational flexibility to meet environmental objectives.

Use of Matrix. Priority number determined by multiplying the category number by weighting factor for each category and adding the results.The lowest value would have the highest preference.

Once the analysis of the options was completed, the results were normalized and applied to the matrix. Since the normalized values for the Net Benefits did not yield a spread. Each option was weighted at middle of the range.

The results of the evaluation were placed into the Prioritization matrix with the following result.

TABLE 7
PRIORITIZATION SUMMARY

OPTION	Net Benefits of Resources/Loads	Agency Additional Administrative Cost	Operational Flexibility	Prioritization Factor
Load Following with third party as Scheduling Coordinator	**2**	**1**	**2**	**10**
Load Following with Western as Scheduling Coordinator	**2**	**1**	**2**	**10**
Load Following with Reclamation as Scheduling Coordinator	**2**	**3**	**2**	**14**
Maximum Peaking with third party as Scheduling Coordinator	**2**	**1**	**1**	**7**
Maximum Peaking with Western as Scheduling Coordinator	**2**	**1**	**1**	**7**
Maximum Peaking with Reclamation as Scheduling Coordinator	**2**	**3**	**1**	**11**

IV. CONCLUSIONS:

The results indicate the preferred option would be to operate the Project in a Maximum Peaking mode with either Western or a third party as Scheduling Coordinator. The discriminator between these two options is the cost of the Third Party Scheduling Coordinator function. The options were analyzed to determine the cost to the two agencies. It would be highly unlikely for a third party Scheduling Coordinator to be able to provide the service for under $64,000 per year, which would be less than one staff member of either agency would cost. **Thus the preferred option becomes the Maximum Peaking option with Western as the Scheduling Coordinator.**